

Energy UK response to ‘Getting more out of our electricity networks by reforming access and forward-looking charging arrangements’

21st September 2018

About Energy UK

Energy UK is the trade association for the GB energy industry with a membership of over 100 suppliers, generators, and stakeholders with a business interest in the production and supply of electricity and gas for domestic and business consumers. Our membership covers over 90% of both UK power generation and the energy supply market for UK homes. We represent the diverse nature of the UK’s energy industry – from established FTSE 100 companies right through to new, growing suppliers and generators, which now make up over half of our membership.

Our members turn renewable energy sources as well as nuclear, gas and coal into electricity for over 27 million homes and every business in Britain. Over 730,000 people in every corner of the country rely on the sector for their jobs, with many of our members providing long-term employment as well as quality apprenticeships and training for those starting their careers. The energy industry invests £12bn annually, delivers £88bn in economic activity through its supply chain and interaction with other sectors, and pays £6bn in tax to HM Treasury.

Executive Summary

Energy UK welcomes the opportunity to respond to the Ofgem consultation ‘*Getting more out of our electricity networks by reforming access and forward-looking charging arrangements*’.

Scope of the Significant Code Review: In taking forward the review, we welcome Ofgem to launch a Significant Code Review (SCR). We note that once Ofgem make a decision on what they wish to address, members will be more able to comment on what should be in the scope of the SCR and how the review should be progressed. We would expect that a thorough whole-system cost-benefit analysis would be undertaken assessing the impact of Ofgem’s proposals on whole system costs, including impact on emissions and the ability to meet decarbonisation targets. We do not consider that the work done by the task forces or Baringa’s study are detailed enough to evidence Ofgem’s proposals as currently set out.

Prioritisation of work streams: We agree that it would be beneficial to prioritise reviewing options on the distribution level, however it is important for whole-system impacts to consider whether changes, especially fundamental changes, would introduce undue discrimination across both the transmission and distribution networks. The uncapped uncompensated curtailment risk that is faced by most new distribution generation due to their non-firm access rights results in heavy distortions on the distribution network. We therefore believe that the key matter to be reviewed is the firmness of access on the distribution networks.

Timetable: The timescales are very tight for this wide ranging reform. If there are delays in the process, there is a large risk that the implementation timescales are squeezed. It is vital that Ofgem properly plans the SCR timeframe, in particular the implementation period of any solutions. Appropriate lead times are required to allow investment and commercial decisions to be made with certainty.

To date, there have been many good opportunities to engage with Ofgem as well as useful information dissemination such as webinars and podcasts. This early engagement is essential for a thorough industry-wide review to take place. Going forward, we welcome frequent opportunities to engage, similar to the Charging Futures Forum process.

Our responses to the questions asked in the consultation document are set out below. Should you have any questions, please don’t hesitate to get in contact.

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Question 1: Do you agree with the case for change as set out in chapter 2? Please give reasons for your response, and include evidence to support this where possible.

Energy UK welcomes this consultation and agrees that reforming some access rights and charges in good time (ahead of the popularisation of electric vehicles and heat pumps – low carbon technologies (LCTs)) could be beneficial in encouraging more efficient network utilisation and reinforcement work. Thorough analysis and impact assessment would need to underpin Ofgem's final decisions to avoid unintended consequences. Enabling growth in demand, particularly from new LCTs, while managing constraints on the networks, is a key goal of the review. Ofgem should ensure that the proposed SCR considers the impacts it could have on broader policy.

We are very supportive of moving towards a smart, flexible energy system which makes the most of its existing assets whilst not undermining investment. The building of infrastructure should be encouraged where it offers good value for money for consumers, demonstrated through cost-benefit analysis. For example, the UK government has banned the sale of petrol and diesel vehicles by 2040 and the decarbonisation of transport is expected to result in 323 billion vehicle miles per year to be electrified in the UK. This transition has the potential to add considerable strain on the power network, if not done in a smart intelligent way. Energy UK, through a recent paper¹ is strongly supporting the development of smart charging solutions to limit the physical infrastructure upgrades that would be required from greater electrification. Smart charging has the potential to facilitate further integration of existing and future low carbon generation, particularly intermittent renewable generation, given the battery storage capacity presented by electric vehicles.

Street cable overloads would be very undesirable and the best way to avoid them is advance planning of how to give the right cost signals and what core access rights are appropriate. The case for change is well made.

Question 2: Do you agree with our proposal that access rights should be reviewed, with the aim to improve their definition and choice? Please provide reasons for your response and, where possible, evidence to support your views.

Yes we agree that the access rights could benefit from a review. Enabling growth in demand due to the deployment of LCTs without a review of existing access rights would be challenging without costly network reinforcement. However, it is crucial that the solution does not lead to over-investment.

A system with firm access where price is cost reflective and the party receives compensation for being constrained is less risky as costs are known ahead of time. There is a risk that uncompensated curtailment arising from the non-firm access rights of Distributed Generators (DG), could become more common in future, imposing additional risks on DG. We are broadly supportive of an increase in choice of access rights, but note that too much choice could lead to regulatory arbitrage to avoid paying cost-reflective charges.

Furthermore, when reviewing access rights for smaller consumers, there needs to be a strong focus on consumer protection. For example, a domestic consumer purchasing an electric vehicle is unlikely to know or understand their access rights. Therefore, when designing a solution, Ofgem should give due consideration to the practicality, transparency and simplicity of any solution, as well as whether the solution is consistent with higher policy goals.

Question 3: Specifically, do you have views on whether options should be developed in the following areas as part of a review? Please give reasons for your response, and where possible, please provide evidence to support your views:

¹ <https://www.energy-uk.org.uk/publication.html?task=file.download&id=6576>

- a) Establishing a clear access limit for small users, with greater choice of options (as considered under b) and c) below) above a core threshold – do you agree with our proposal in paragraphs 3.5-3.10 that this should be considered? Do you have views on how a core threshold could be set?**

Yes, we agree that establishing a clear access limit for small users should be reviewed via a SCR process. However, we are unsure of how this will work in practice and are concerned that these options may be unattainable.

- b) Firm/non-firm and time-profiled access – do you agree with our proposal outlined in paragraphs 3.15-3.21 that these options should be developed?**

Energy UK agrees that this should be investigated as part of the SCR. The extent to which active network management is now employed at distribution level should be included in the review.

We believe that improvements in the definition of 'firm' and 'non-firm' access at the distribution level should be of benefit to users in that it would make curtailment risk easier for users to manage. Time-profiled access on the distribution network may be useful in the future, but in this review it is important to concentrate on firm access arrangements. We also note that a party with undefined non-firm access will have difficulty accessing the Balancing Mechanism (or similar), this will be problematic with the aspiration to enable Distribution System Operators (DSOs) to emerge as market facilitators. A market with limited firm access will therefore result in a market with less competition and price discovery.

We note that industry participants with Capacity Market (CM) contracts will want to avoid non-firm access and as a result the inclination for sharing capacity is low. Long term access (by which we mean evergreen) will always be important for all network users, and certainty is required for securing new investments and ensuring that existing investment is not undermined. Distribution users should be able to be financially firm such that those users who are prepared to pay for full use of the system can get that level of access, or equivalent. This network investment trigger is a fundamental component for enabling price discovery to deliver economically efficient network reinforcement.

- c) Duration and depth of access, discussed in paragraph 3.22-3.32 - would these options be feasible and beneficial?**

Short term access is available at transmission level but is expensive and is not the choice of most developers and as a result is rarely used. It is not clear if it would be useful at DG voltage levels, as the issue would remain that developers tend to want long term certainty of access to the market. Market participants with CM contracts, if required to renegotiate their access rights partway through their 15-year contract, will be in a difficult position if they find it is more expensive or no longer available. Therefore, it is likely that the majority of parties will elect for evergreen access rights over access rights which are for a duration of 15 years or less.

Regarding depth of access we are of the view that this would be challenging and not altogether desirable. For example, locally generated electricity still benefits from the frequency control, harmonics control etc. that come from being connected to the wider grid. Access arrangements that introduce shallow or local access rights could inhibit the trading of power or create local markets, which risks fragmenting the GB trading arrangements.

- d) Should options be developed at transmission or distribution in particular, or are both equally important?**

We agree that it would be beneficial to prioritise reviewing options on the distribution level, however, it is important for whole-system impacts to consider whether changes, especially fundamental changes, would introduce a distortion across both the transmission and distribution networks. The uncapped uncompensated curtailment risk that is faced by most new DG due to their non-firm access rights results in heavy distortions on the distribution network.

Proper thought needs to be given to transitional arrangements of any changes made by a SCR. Clearly, large changes in charges can have a material impact on customers and wholesale market participants. Transitional arrangements may be needed to ensure that affected parties are able to respond as effectively as possible to any new methodology which is put in place. These transitional arrangements may include reasonable notice periods and/or phased implementation, proportionate to the degree of change.

Question 4: Do you agree with the key links between access and charging we have identified in table 1? Why or why not? Do you think there are other key links we have not identified? Where possible, please provide evidence to support your views.

At this time, Energy UK agrees with the key links currently identified between access and charging.

In addition to the key links in the document, we note that there is no current cost-reflective assessment DNOs can undertake to assess the cost of curtailment versus the cost of reinforcing the network. This is due to the number of assets with non-firm access, where curtailment is often unrecorded. With more firm access arrangements in place with DNOs, there will be clear evidence for the cost benefit of reinforcement of distribution networks. It will, therefore, be important for DNOs to keep a thorough log of the assets connected to their network.

Question 5: Do you agree with our proposal that targeted areas of allocation of access should be reviewed? Please give any specific views on the areas below, together with reasons for your response. Where possible, please provide evidence to support your views:

a) Improved queue management as the priority area for improving initial allocation of access, as outlined in paragraphs 3.41-3.44?

We agree that improved queue management would be a desirable outcome to aim for and should be considered a priority area for improving initial allocation of access. However, we note that a number of work streams have progressed in this area which may improve queue management. This area could therefore be considered as a 'stand-alone' activity or left out of the SCR.

Connect and Manage (C&M) style arrangements should not be ruled out at this stage. Many aspects of the arrangements could be useful to the system and should be considered; namely, firm access. Energy UK considers arrangements could be explored at the distribution level in order to better manage connections queues. Considerations would need to be given to properly manage constraints e.g. generation and demand submitting bids and offers similar to that in the BSC, or placing a cap on the amount of time a BMU can be constrained. This will better assist parties in managing the risk to their assets. Care would need to be taken to ensure that a Connect and Manage regime does not place unreasonable costs on customers.

A suitable solution could take time to develop and implement. However, with the degree of change needed, this is the opportune moment to ensure the best solution is chosen.

b) Not to consider the potential role of auctions for initial allocation of access as part of a review at this time, as discussed in paragraph 3.44?

We fully support Ofgem's decision not to consider auctions for initial allocation of access. Whilst auctions may work in economic theory, their impacts in the real world would be influenced by inevitable gaming and favour some industry participants over others. Ultimately the consumer would pay more for access allocated by auction whether for initial allocation or reallocation. The reason for this is that currently network access is sold at cost rather than at value.

c) To review the areas outlined in paragraphs 3.45-3.48 to support re-allocation of access?

There is evidence for significant amounts of unutilised capacity on the distribution system. Therefore, Energy UK agrees that the re-allocation of access should be reviewed. Cost-reflective charges may

ensure that there is an incentive to use or let go of any unutilised capacity. Our members believe that a 'use it or sell it' access condition could incentivise capacity hoarding if the price is set at value. A more sensible condition could be for unutilised capacity to be sold back to the network operator.

Before the implementation of the CMP192 User Commitment methodology there was a 'TEC amnesty' which resulted in 175MW of access rights being returned in SHE Transmission's area. This meant that reinforcements were reconsidered and allowed some generators to have the opportunity to advance their connection date. However, without a clear set of rules outlined (for example in the CUSC) it was impossible for contracted generators or third parties to independently determine what the impact of this 'released' capacity was and/or validate the fairness of how the 'queue' was subsequently managed.

Question 6: Do you agree that a comprehensive review of forward-looking DUoS charging methodologies, as outlined in paragraphs 4.3-4.7, should be undertaken? Please provide reasons for your response and, where possible, evidence to support your position.

We support a review of the DUoS charging methodologies, including a harmonisation of DNO charging methodologies such that all DNO areas use a single Extra high voltage Distribution Charging Methodology (EDCM) model. If distribution charges are to be more closely aligned with transmission charges, where it is proven that doing so would reduce distortion, it makes sense to also harmonise charging methodologies across all distribution networks.

We agree with reviewing the balance of capacity-based and time-of-use charges. However, it should not be assumed that moving towards capacity-based charges is more cost-reflective. As you move further away from the point of connection of a customer, it is the diversified demand of that customer along with all other customers that will drive network investment, and so it may be more appropriate to maintain a time-of-use usage based charge for these remote network levels. It should be noted that there will need to be an operational way of managing distribution constraints. This could take the form of an extension to the Balancing Mechanism (BM) which can take advantage of the development of DSOs, (or other similar framework as currently under development through the Open Networks Project).

The Targeted Charging Review (TCR) is reviewing the current system of network residual charges. It is important that a review of forward-looking DUoS charging methodologies should keep the TCR in mind and ensure that the two are consistent going forwards. We highlight that it is important to bear in mind that residual charges are not to incentivise industry behaviours, and are purely a cost recovery mechanism.

Ofgem should consider whether there would be cost-benefit of introducing more locational granularity into the Common Distribution Charging Methodology (CDCM). The current charging methodology may not provide the correct or sufficiently useful incentives to encourage connections at locations which are demand or generation heavy. As with any review, we would expect that a thorough whole-system cost-benefit analysis would be undertaken assessing the impact of the proposals on whole system costs, including impact on emissions and the ability to meet decarbonisation targets. We do not consider that the work done by the task forces or Baringa's study are detailed enough to evidence Ofgem's proposals as currently set out.

The EDCM models as they stand are too complicated to draw any discernible signal to influence party behaviour. While this may make the models cost-reflective, a review of the models is welcome to investigate whether there is a trade-off to make them more simple and transparent. There is the potential to bring the EDCM closer in line with how TNUoS works.

It is important to note that locational charging signals are mainly influential at the time of deciding where to locate a generation project and when to close it, although they can also have an impact on mothballing and upgrading decisions during the lifetime of an asset. Volatility in the locational element of charging caused by other network users coming online or going offline is a risk beyond the control of the generator operator, and can have a material negative impact on the cost of financing new and operating existing plant. Therefore, it is important to reach an appropriate balance between the cost reflectivity,

predictability and volatility of charges. We are concerned that Ofgem's proposals regarding locational DUoS will mean that charges become more unpredictable and volatile.

Please note that the DCMF EHV charging methodology review in 2015 *"did not find any evidence that network reinforcement has been deferred due to the response of EHV customers"* to the *"main driver of the EDCM [which] was to introduce charges/benefits that would encourage generation to locate where growth in demand would otherwise require network reinforcement"*. It would be worth updating this analysis as part of the review.

Question 7: Do you agree that the distribution connection charging boundary should be reviewed, but not the transmission connection boundary? Please provide reasons for your response and, where possible, evidence to support your position.

We agree that it is worth reviewing the boundary as set out in the consultation document. Moving to a shallower connection charging boundary at distribution could reduce barriers to entry for those wanting to connect to the distribution network, as it would mean that new connections would no longer principally bear the costs of any reinforcement. We highlight that a move to a shallower connection charging boundary would need an appropriate transition. In particular, a hiatus could occur in connections requiring reinforcement as parties wait for the new arrangements to become effective. We reiterate the need for a whole-system cost benefit analysis including the impact on emissions and the ability to meet decarbonisation targets. We do not consider that the work done by the task forces or Baringa's study are detailed enough to evidence Ofgem's proposals as currently set out.

As we wrote in answer to question 6, in consideration of locational charging for a shallow boundary, it is important to note that locational charging signals are mainly influential at the time of deciding where to locate a generation project and when to close it, although they can also have an impact on mothballing and upgrading decisions during the lifetime of an asset. Volatility in the locational element of charging caused by other network users coming online or going offline is a risk beyond the control of the generator operator, and can have a material negative impact on the cost of financing new and operating existing plant. Therefore, it is important to reach an appropriate balance between the cost reflectivity, predictability and volatility of charges.

Under the connection charges for DG at present, the cost of reinforcing the network is being focused on one newest generator. This may deter them from taking forward their project, meaning that new network capacity isn't taken forward even if there is wider demand for it. All parties connected to the system contribute to its incremental cost, regardless of how long the party has been connected. This principle of shallow connection charges is reflected in transmission network charges but is lacking in distribution network charges.

Question 8: Do you agree that the basis of forward-looking TNUoS charging should be reviewed in targeted areas? If you have views on whether we should review the following specific areas please also provide these:

- a) Do you agree that forward-looking TNUoS charges for small distributed generation (DG) should be reviewed, as outlined in paragraphs 4.19-4.23?**

In order to properly align the charging principles between generators, forward-looking TNUoS charges for small DG should be reviewed in parallel with the distribution access of transmission-connected generators. The goal should be to assess whether there is currently undue discrimination and unjustified market distortion and whether Ofgem's proposals would remove this as far as is practicable. As in our previous answers, we call for a whole-system cost-benefit analysis as we do not consider that the work done by the task forces or Baringa's study are detailed enough to evidence Ofgem's proposals as currently set out.

b) Do you consider that forward-looking TNUoS charges for demand should be reviewed, as outlined in paragraphs 4.24-4.27? Please provide reasons for your response and, where possible, evidence to support your position.

Yes we consider forward-looking TNUoS charges for demand should be reviewed. Periods of system peak do not always coincide with Triads.

Question 9: Do you agree that a broader review of forward-looking TNUoS charges, or the socialisation of Connect and Manage costs through BSUoS at this time, should not be prioritised for review? Please provide reasons for your response and, where possible, evidence to support your position.

Yes, we agree that a review of these topics should not be addressed in the SCR. However, interactions these topics may have with those covered by the SCR should be considered by Ofgem to ensure there are no adverse impacts. The methodology for setting forward-looking TNUoS charges was reviewed relatively recently through Project Transmit and there is limited total change bandwidth and the more pressing review of DUoS and firmness of access on the distribution network should take priority. Whole-system impacts should be considered though, please see our answer to question 3d.

As to the socialisation of the cost of transmission constraints, there is not a clear case for locational collection of these costs. In any event, the belated commissioning of the West Coast HVDC Link and of Caithness Moray will reduce constraint management costs related to Scotland.

Energy UK notes that the TNUoS year-round charge is cost reflective to account for potential constraint costs. Therefore, trying to make BSUoS cost-reflective in relation to constraint costs, as opposed to a cost recovery mechanism, would be double counting. The TNUoS year-round charge, which was brought in to reflect the new “year round” criterion in SQSS, is simulating (calculating the cost of) investment in new transmission lines, in relation to an increment of generation at each node for which a TNUoS price is calculated as part of the process. For distant nodes, the modelled electrical path to demand will be long, so there will be many circuits for which an increment in their capacity is shown to be needed in the TNUoS charge calculation method, and the cost of each circuit’s extra modelled flow (capacity) will be summed into that node’s TNUoS.

Question 10: Do you agree that there would be value in further work in assessing options to make BSUoS more cost-reflective, and if so, that an ESO-led industry taskforce would be the best way to take this forward?

No, we do not agree. BSUoS is not currently intended to be cost-reflective, as it is effectively equivalent to a ‘residual’ charge and recovers costs incurred for balancing the system ex-post. Any attempts to change the very nature of BSUoS and make it ‘cost-reflective’ would be changing significantly the way system balancing is not only charged, but also bringing into play another cost which may drive behaviours. This could lead to significant unintended consequences. As per our answer to question 9, the cost-reflective element for constraint action is addressed in TNUoS, therefore, it is unnecessary to also reflect this in BSUoS. Should there be any changes to BSUoS, it should retain the principles of a socialised cost recovery charge and not introduce any distortions between industry parties.

We think that generally the services that underscore BSUoS are of benefit to all users over time, for example reserve, frequency response, reactive power and black start. Attempting to disaggregate BSUoS and allocate costs differentially would be very complex and distracting to do, and add risk for users.

Question 11: What are your views on whether Ofgem or the industry should lead the review of different areas? Please specify which of SCR scope options A-C you favour, or describe your alternative proposal if applicable. Please give reasons for your view.

Some members believe that a narrower approach is most sensible and covering more than this scope has the potential to be covering too much at once. However, other members believe a comprehensive review is necessary in order to properly remove all distortions associated with network charging

Reforms which Ofgem decide not to take forward under the umbrella of the SCR, but which parties to the relevant Codes will be expected to raise, should have strategic direction clearly set out by Ofgem. Failure to do this could result in a skewed understanding and outcome, which would ultimately take longer to work through.

Question 12: Do you agree with our proposal to launch an 'Option 1' SCR for areas of review that we lead on? Please give reasons for your view.

The Option 1 approach to a SCR change process represents the approach taken in the past. We support the proposal.

It is essential that the solution is well defined before the modification is raised. This approach should be kept under review and the scope of the SCR should be widened if industry is not making sufficient progress.

Ofgem should actively participate in the industry Code modification processes which are progressed as a result of this work but that do not remain within the SCR in order to keep them under review and ensure the scope is correct.

Question 13: Do you agree with the introduction of a licence condition on the basis described in paragraphs 5.11 and 5.12 and Appendix 5? Why or why not? Do you have any comments on the key elements set out in table 7 of Appendix 5a, or consider there are any other key elements which should be included? Please give reasons for your view.

While we believe this is an appropriate way forward, the timescales for delivery in section 5 of Appendix 5a, look challenging. Modifications would need be raised by the licensees by June 2019, and Final Modification Reports submitted to Ofgem by March 2020. In addition, licence conditions could also be placed on TOs as this will ensure further engagement.

It is vital that Ofgem properly plans the SCR timeframe, in particular the implementation period of any solutions. With such a tight timeframe in mind, it could be easy for the process to drag and deadlines be missed. Energy UK urge Ofgem to not grant derogations to the 15-month minimum implementation timeframe for charging changes in the DCUSA. We further encourage a sufficient implementation period in other Codes. We understand the need for a swift end to any distortions, but with the potential for such large changes to the charging framework, a long notice period is preferable.

Question 14: Do you have any comments on the draft wording of the outline licence condition included at Appendix 5b? Please give reasons for your view.

Appendix 5b again specifies a very challenging timeframe, which may be hard to achieve without curtailing industry debate.

Question 15: What are your views on our indicative timelines? Do you foresee any potential challenges to, or implications of, the proposed timelines and how could these be mitigated?

As per our answer to question 13 we wrote that the timescales for delivery in section 5 of Appendix 5a, look challenging. Modifications would need be raised by the licensees by June 2019, and Final Modification Reports submitted to Ofgem by March 2020. In addition, licence conditions could also be placed on TOs as this will ensure further engagement. It is vital that Ofgem properly plans the SCR timeframe, in particular the implementation period of any solutions. Energy UK urge Ofgem to not grant

derogations to the 15-month minimum implementation timeframe for charging changes in the DCUSA and to allow for a sufficient implementation period for modifications in other Codes.

As per our answer to question 14 we wrote that Appendix 5b again specifies a very challenging timeframe, which may be hard to achieve without curtailing industry debate.

Ofgem should indicate which reforms are related to ensure the industry Code modifications are coordinated and are implemented at the same time. Any reforms that are 'stand-alone' should be progressed quickly to ensure resources can be allocated to the more complex work streams. Ofgem should ensure that sufficient detail of direction and expected outcomes are set before code modifications are raised by industry. This will prevent issues arising later and ensure that modifications can progress swiftly.

Appropriate lead times are required to allow investment and commercial decisions to be made with certainty, for example, timescales should consider the T-4 capacity auction, supply contract lengths, price cap arrangements, etc.

We are concerned at the proposed timescales. There are fixed implementation dates, yet no provision is made for any deadlines being missed along the way. Timescales are very tight for this wide ranging reform. If there are delays in the process, there is a large risk that the implementation timescales are squeezed. This causes huge financial uncertainty to customers and market participants such as suppliers and generators who have to pay these charges.

Transparency of what the new methodology changes will be, and a long lead time is essential. There could be some large winners and losers as a result of this regulatory review of the charging methodology. Regulatory change should not result in short term windfall gains or losses. Customers on 'pass through' contracts need to have notice of these changes to charges, and to be able to adapt and incorporate into their budget planning cycles.

Suppliers also need this notice period / clarity around the charging methodology to ensure that they accurately reflect the new charging arrangements for customers on 'fixed price' contracts. A supplier can only pass through the charges at the time of pricing a 'fixed price' customer. If implementation timescales are short, any changes will not be seen by the customer until the time they are next priced – which may be 1-3 years out. Increased transparency of the methodology / longer lead times will lead to reduced risk premia being added to customer contracts.

At the point of raising modification proposals in the second half of 2020, there should be a sufficient level of detail for market participants to be able to predict what the new charges will look like for their customers. Suppliers and DNOs should have enough information available to them to be able to engage with customers on how their charges will change and how they could respond to these changes. For appropriate signposting for all market participants and in respect of market liquidity, we think it appropriate to have a three-year period following a clear decision on the final methodologies before implementation. That would equate to an April 2023 implementation if the relevant modifications follow the suggested timescales from the consultation document. This will give all types of network user affected by these changes more time to understand and budget for these changes. Suppliers will be able to reflect the changes into customer contracts. If detailed modifications are not raised in the second half of 2020, then Ofgem should look to move the implementation date. We would encourage Ofgem not to derogate the DNOs' required 15 month notice period.

Question 16: What are your views on our proposals for coordinating and engaging stakeholders in this work?

Coordination across work areas will be important, as reforms to access and charging are deeply intertwined. The obligation on each licensee to develop its assessment and proposals in consultation with any other persons whose interests are materially affected by the Relevant Arrangements, is worthwhile.

To date, the Charging Futures Forum (CFF) days have been well attended and have driven important and useful discussions. Additionally, the webinars are valuable for stakeholders who cannot or do not attend the CFF. Energy UK encourages Ofgem to continue to attend industry fora such as the TCMF, DCMDG, and other like meetings. Energy UK and our members welcome further such opportunities for engagement.